The Portfolio of Generation Facilities in Japan's Electric Power Sector,

Past and Future

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Preface

Japan consumes a considerable amount of the world's energy, and it occupies an even more important position in the markets for internationally traded energy. Because sufficient domestic fossil-fuel reserves are not economically available to sustain the nation, Japan currently imports:

- 5.7 million bbl/day (329 million kl in 1994) of petroleum, one-eighth of the total traded internationally
- 56 billion cubic meters of natural gas annually (43 million tons in liquefied form in 1994), one-fifth of the total natural gas traded internationally (and 65% of the total traded in the form of liquefied natural gas, LNG)
- 120 million tons of hard coal annually (in 1994), one-quarter of the total amount traded internationally

Japan's electric power sector is a major consumer of these natural resources, burning 30 million kl of petroleum, 35 million tons of LNG, and 47 million tons of bituminous coal in 1997. The sector generated more than 300 million MWh of electricity from nuclear power in 1996, equivalent to 74 million tons of crude oil.

The Japanese electric utility sector faces conflicting pressures, which will affect international energy markets. On the one hand, the sector is beginning a process of deregulation that will make portfolio choices less subject to what is widely perceived to be strong government guidance on energy choices. On the other hand and in response to the Kyoto Protocol, the Japanese government has indicated its intention to achieve a major part of the required greenhouse gas emission reduction by a significant increase in the amount of nuclear power capacity (25 GWe by 2010). In addition, the significant decline in the growth rate of demand for electricity resulting from the stagnating national economy further complicates the outlook.

This paper proceeds in two parts. In the first part, the evolution of the current portfolio of generation facilities is examined. Particular focus is given to the role of the frequently stated policy goal of energy diversification. Although Japanese government policy was an important element in shaping generation facilities, the choices made by Japanese electric utilities are not notably different from those made by electric utilities in other countries. Moreover, diversification of energy sources was as much a result of other policy goals, such as environmental control in urban areas and the development of nuclear power, as an explicit policy of diversifying energy sources.

The second part of the paper examines the prospects for further changes in the portfolio of generation facilities over the next decade based on an analysis of current conditions. Forecasts for a significant increase in nuclear power capacity do not appear realistic, and the prospective capacity additions do not appear likely to change the current portfolio mix significantly.

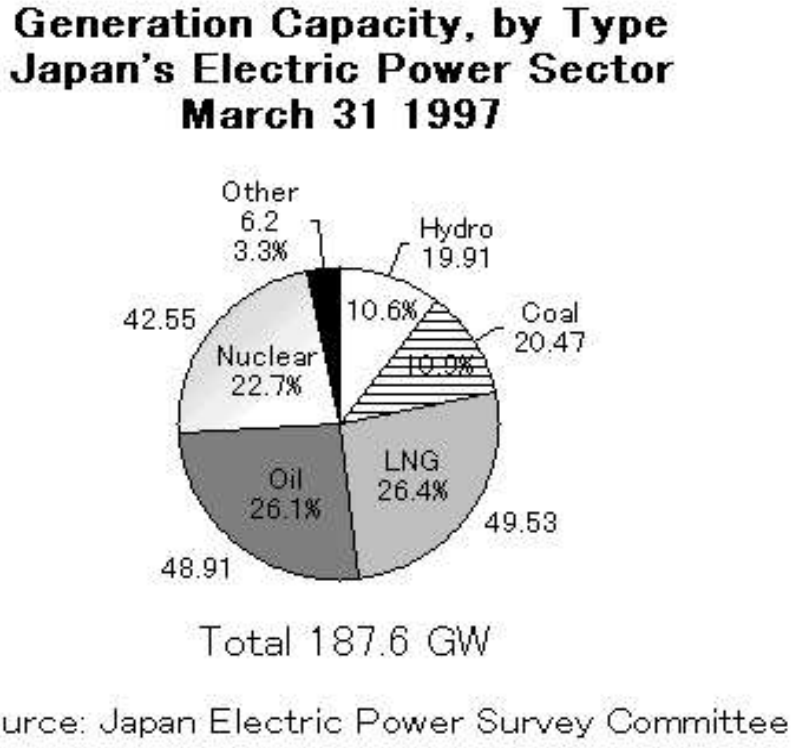
I. Japan's Portfolio of Generation Facilities, Past to Present

Most observers would say that Japan's electric power sector has diversified its sources of energy and balanced its portfolio of generation capacity among facilities powered by hydro, thermal, and nuclear resources. However, this "balanced portfolio" is simply an accumulation of choices made over time by participant companies in the sector. Companies focused at different times on adding operations to utilize particular resources that appeared advantageous at the time. As a result, Japan's electric power sector acquired today's portfolio as an accumulation of companies' choices for generation resources that were considered available and economical at the time the choices were made. Among other things, such choices took into account environmental regulations in metropolitan areas.

A. Portfolio to Date

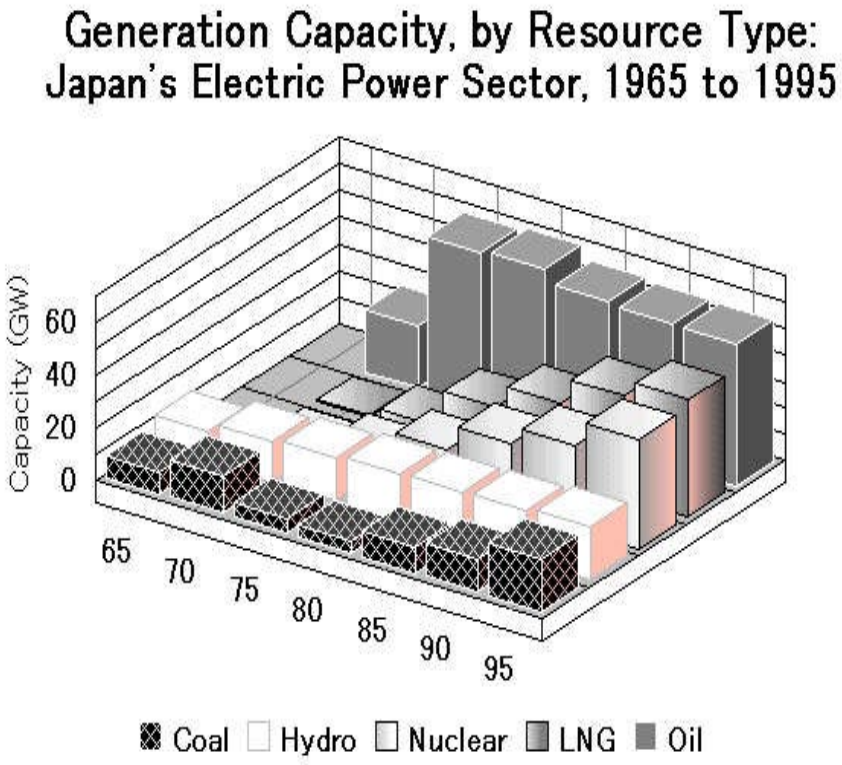
1. National portfolio

As of March 1997 (the end of the Japanese fiscal year 1996), Japan's electric power sector owned and operated 188 GW of generation facilities (**Figure 1**). Oil, LNG, and nuclear power each accounted for nominally one quarter of the total power capacity, and hydro and coal shared equally the rest, essentially. Figure 1 doesn't include hydro-pumping storage (23.2 GW) and self-generation units (22.9 GW) owned by major power consumers that were themselves powered mainly by fossil fuels.

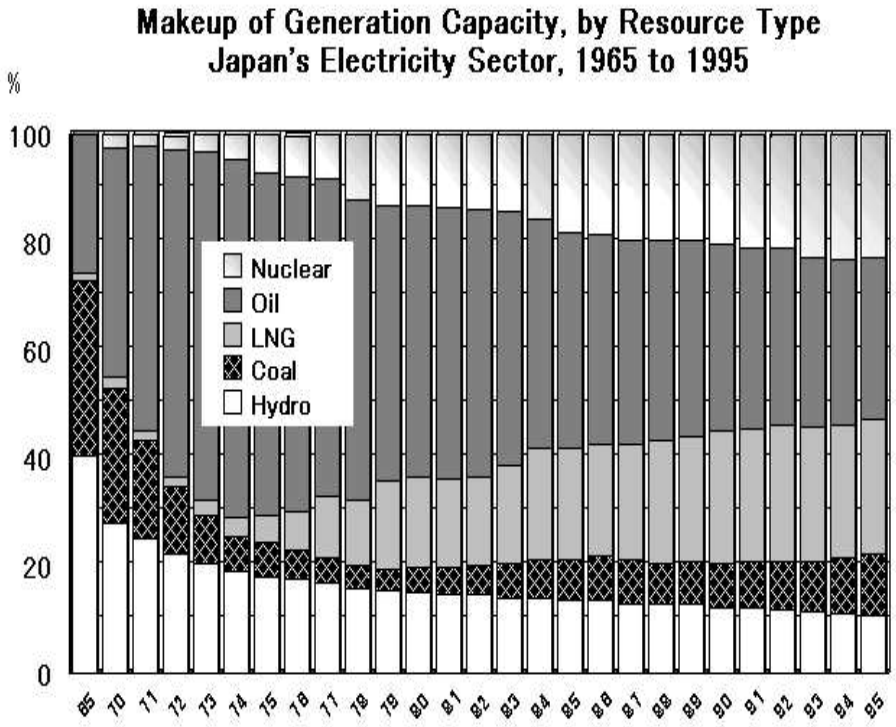


(Figure 1)

This portfolio is sometimes described as "balanced," as we have noted, and company CEOs and government executives claim to have contributed to the energy diversification. However, the real prime movers behind diversification did not differ significantly from those that have been operative in other OECD countries: namely, policies of less dependence on petroleum, as the International Energy Agency (IEA) has asserted. Like other OECD countries, Japan pursued ways to substitute for petroleum in order to satisfy increasing demand for electricity without applying undue pressure on the crude-oil market. Japan's electric power sector has installed LNG and nuclear generation units during the last three decades partly to escape its heavy dependence on overseas oil (**Figure 2a, 2b**).



(Figure 2a)

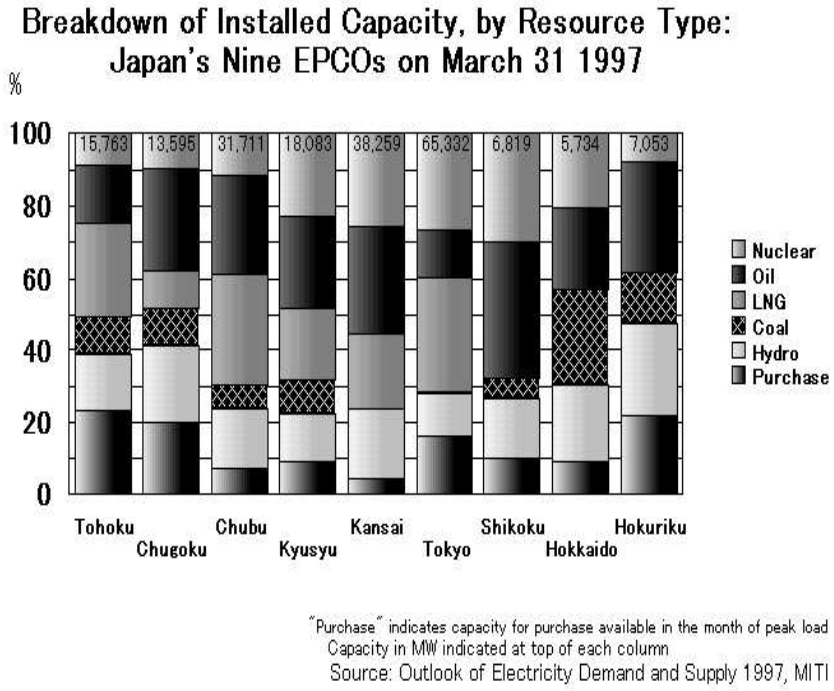


(Figure 2b)

2. Company portfolios

Figure 3 shows installed capacity of Japan's nine major electric power companies (the "Nine EPCOs"), by generation resources. The Nine EPCOs are vertically integrated, investor-owned utility companies that dominate Japan's electric power sector. Each of the Nine EPCOs has its own diversified portfolio for generation, including hydro, fossil fuel, and nuclear power. These portfolios differ considerably, especially in their nuclear and LNG deployment, although each company tends to acquire the generation resources whose proportions in its own portfolio are small relative to the corresponding average proportions in the portfolios of other companies among the Nine EPCOs. For example, at the same time Tohoku EPCO is constructing nuclear units, Tokyo EPCO and Kansai EPCO are building coal units. Another point of note is that some interconnections between the Nine EPCOs' electric power systems have inadequate capacity to form a single integrated system for the entire nation. In fact, Japan's electric power system consists largely of three smaller systems—or, more precisely, nine subsystems, each run by one of the Nine EPCOs. The balance displayed in Figure 1 is thus just a summation of the variety exhibited within all the electric power companies: each of the Nine EPCOs functions under circumstances that differ from those of the other EPCOs. Each has its own well-balanced portfolio in the

sense that it doesn't rely on a single resource[1]. It is rather difficult to determine which company is "best balanced" and how well balanced the aggregated number for the whole nation is in comparison to the corresponding aggregated numbers for other nations.



(Figure 3)

Note: Figure 3 counts the generation capacity owned by wholesale companies as part of the available capacity for each of the Nine EPCOs' power purchase during the month experiencing peak load. In this respect, Figure 3 differs from Figure 1, in which the generation capacity owned by wholesale companies is counted by nameplate capacity alone.

3. Portfolio function in resource procurement

In Japan, the advantage of diversification is strongly emphasized by the Nine EPCOs in the context of energy procurement; and, as just noted, a tendency to add capacity from the energy resource with the least weight in the current portfolio can be observed. Dependence on one particular generation resource concentrates risk in resource procurement and diversification reduces this concentrated risk; however, the electric power sector must then manage additional risks introduced by a number of energy resources, as it diversifies its generation resources. Diversification never eliminates risk for the sector. As

[1] Wholesale companies, on the other hand, specialize in particular generation resources. For example, EPDC is a government-financed wholesale company generating electricity from coal and hydropower; jointly-owned units are owned jointly by steel companies and some of the Nine EPCOs, utilizing derivative gases from steel production as well as coal, in many cases.

one specific example, Japan's electric power sector during the "Oil Shock days" relied heavily on overseas oil; it was therefore seriously hurt by increases in the price of crude oil. The sector has, since that time, sought substitute resources, accepting the associated risks. It has installed nuclear units that must be run at a high utilization rate to remain cost-competitive, even when fossil-fuel prices decrease and procurement eases, or when new entrants to the power-generation market use cheap coal and oil, threatening the traditional power companies. While the possible risks of nuclear power are well known (e.g., stranded assets, political adversity, and public sentiment), LNG and coal pose their own risks for companies in the sector. Because the worldwide markets for LNG and coal were relatively immature when Japan's electric power sector began acquiring these resources, a "take-or-pay" clause was required in long-term contracts in order to keep the development financing viable. These contract provisions obligated the sector to purchase a predetermined amount regardless of the future competitive position of that fuel. While such measures diversified the energy generation portolio, the assumption of such market risk for overseas developers diminished the sector's flexibility in procurement.

While we can judge Japan's diversification to have been a success for the past three decades, generally, we show below that energy diversification was not the only, and perhaps not even the major, factor influencing energy choices.

B. Background of the Portfolio

Behind the current generation-facilities portfolio of Japan's electric power sector lie two principal issues: an economically driven policy reducing the nation's dependence on crude oil, and an environmentally motivated resolution to reduce pollutant emissions in metropolitan areas. In addition, policies to develop nuclear power and to protect domestic refining also influenced the portfolio of generation facilities.

1. The policy decreasing companies' and the government's dependence on oil

Two Oil Shocks hit Japan, in 1973 and 1979, that rather traumatized the Japanese government. Since then, the government has strongly advocated measures to avoid disruption in the supply of overseas crude oil. During the Oil Shocks, import prices of crude oil showed sudden spikes. Japan had no other recourse but to continue buying oil, as expensive as this had become, and consequently suffered with other oil-importing countries. Japan was unable to reduce its petroleum consumption by even 2%, though prices increased multiple-fold. National petroleum consumption declined only slightly, from 4.95 million bbl/d during 1973 to 4.86 million bbl/d during 1974, and from 5.05 million bbl/d during 1979 to 4.96 million bbl/d during 1980. During those days, Japan's electric power sector relied heavily on petroleum as a generation resource, while pressures to increase electricity demand were stronger than ever. The sector suffered, as a result. The national government instituted price controls and froze rates for public services, from railroad fees to standard prices of rice, for several months. The Nine EPCOs suffered from

the gap between increasing costs and depressed revenue from frozen electricity rates until the government agreed to increase the rates, then suffered from a decline in demand due to the rate increase. The rising nationalism among oil-exporting countries had raised increasing doubts within the electric power sector throughout the 1960s, and the Oil Shocks conclusively determined Japan's direction in this respect, as well as that of other oil-importing countries. With forecasts that crude-oil prices would continue to soar, petroleum no longer appeared to offer an attractive, economical generation resource for Japan's electric power sector; the sector therefore inclined toward substitute resources[2]. In 1980, legislation for energy substitution[3] passed the Diet, backed by an IEA recommendation, and the Ministry of International Trade and Industry (MITI) established a guideline[4] essentially prohibiting Japan's electric power sector from planning additional oil-powered generation units. This restriction on the construction of additional oil-powered units was lifted in 1998 (but only for units to be used other than as base-load units), in response both to lower crude oil prices and to the influx of independent power producers (IPPs) into the sector with competitive oil-powered projects.

2. LNG deployment to reduce air pollution

Together with Japan's policy to reduce the nation's dependence on oil, environmental considerations played an important role in moving Japan's electric power sector toward its eventual acquisition of today's portfolio of generation facilities. The environment posed an issue even before the Oil Shocks, and environmental considerations predated Japan's policy of less dependence on oil. In fact, LNG deployment began as a way to reduce air pollution in metropolitan areas.

Air pollution became a serious concern in the 1960s. During two decades of robust economic growth beginning in the late 1950s, industrial metropolitan areas utilized increasing amounts of petroleum. As a consequence, in 1965, Japan's petroleum consumption reached a level ten times the 1955 level, and sulfur dioxide concentration in the atmosphere reached 0.06 ppm in major metropolitan areas. Even earlier, Japan's electric power sector had begun making decisions about generation resources that took into consideration air pollution, led by Tokyo EPCO, whose service territory faced the worst problems. The companies had never put environmental priorities before fuel cost, however. For example, Tokyo EPCO chose to shift fuel from domestic coal to fuel oil in 1962, not only to reduce emissions, but

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[2] Even without deregulation, regulated companies have had incentive to avoid the deployment of resources whose prices are expected to increase. Because the rates of services to recover their costs are set by regulatory entities beforehand, companies risk failure to fully recover their costs when they use resources whose prices are increasing and pressuring further cost increases. On the other hand, companies can earn windfall profits when they use resources whose prices are decreasing. The causative phenomenon underlying both situations is termed *regulatory lag*.

[3] "Law facilitating the introduction and development of substitute energy resources for petroleum, 1980" (Sekiyu Daitai Energy Hou of 1980).

[4] "Guideline for power and manufacturing companies to facilitate energy substitution" (Sekiyu Daitai Energy Shishin, 1980).

also to move away from domestic coal, the cost of which was losing its competitiveness to fuel oil. Another Tokyo EPCO decision, later in the 1960s, to burn crude oil directly as the generation resource was also made under circumstances of a tight domestic market for fuel oil (a principal product of petroleum those days) and of fuel-oil prices that had risen higher than crude oil. This decision also took into account the environmental consideration that crude oil from Southeast Asia and China contains less sulfur than does fuel oil, not only because of sulfur concentration through the refinery process, but also because crude oil from Southeast Asia and China contains less sulfur than crude oil from elsewhere. Environmental considerations were thus a factor in Japan's energy-related considerations before LNG deployment, but they figured secondarily to cost.

LNG deployment laid a cornerstone in the sense that the power sector put first priority on environmental considerations relative to cost issues. In the early 1960s, Tokyo EPCO planned to build a thermal plant powered by fuel oil in Yokohama City, a metropolitan area. The mayor of Yokohama City, however, expressed strong concern about the prospect of an additional source of pollution, and urged the company to reconsider, or even halt the project. After years of debate, Tokyo EPCO decided to burn LNG at the site in 1965, though the company's analysis had concluded that LNG units would cost 30% more than oil units. LNG units emit far less air pollution because natural gas is easy to desulfurize through a liquefying process, and LNG contains no nitrogen. As a result of this decision, the first LNG generation unit in the world started operation in 1970. The city's action preceded both the national Pollution Prevention Policy Act of 1967 and a national regulation on sulfur dioxide concentration, which took effect in 1968. The city's action laid the foundation for local governments' jurisdiction over environmental issues through their authority over siting questions.

The overall process at Yokohama City evolved to a "total amount" measure, by which a local government may limit the total amount of air pollution emanating from each emission source in its area of jurisdiction. The Environment Agency for the nation began designating cities in which the measure should be adopted for sulfur oxide (1974) and for nitrogen oxide (1981) emissions. As cities' regulations became more stringent, LNG was increasingly introduced to resolve environmental as well as oil-dependency concerns.

3. Nuclear installations

Nuclear power has played an important role in Japan's electric power sector's efforts to balance its power-generation facilities portfolio. Japan's propensity toward nuclear power is understandable as a means to both decrease the nation's dependence on oil and address environmental concerns.

The history of Japan's nuclear development begins with the establishment of the national Nuclear Institute in 1956 and the Japan Atomic Power Company (JAPC) in 1957. JAPC was established through investments by organizations in the private sector such as the Nine EPCOs and heavy industry. Crude-oil

markets in those days were quite relaxed, so nuclear power was developed as a technological challenge in anticipation of the forthcoming era of massive energy consumption. As the 1960s began, emerging nationalism and signs of impending crude-oil price increases fueled concerns about continuous price increases, and additional concerns about a possible depletion of fossil fuels prevailed worldwide. Nuclear power appeared to be an attractive resource economically, relative to traditional fossil fuels. At the same time, Japan was experiencing serious air pollution, and nuclear power offered hope as a clean energy source answering environmental concerns. Construction began in 1961 on the first commercial nuclear power plant, which JAPC brought online in 1965. The project ensured the feasibility of the technology for Japan's industries. The economic feasibility of nuclear power also increased as a result of the unstable situations created by pressure in the oil markets, and the Nine EPCOs began constructing additional nuclear units. Since 1971, the Nine EPCOs have brought nuclear units online in a continuous succession.

4. Restrictions on petroleum utilization

Along with its policies encouraging greater independence from oil and responding to environmental concerns, Japan's protection of the petroleum industry has impacted the Japanese electric power sector's portfolio of generation facilities. Following the economic disruption of World War II, Japan chronically ran short of foreign currency to purchase input goods from overseas to restore the national economy. In order to secure economic growth, MITI made commitments to heavy industries and allocated foreign currency intensively to the steel and petroleum industries to provide them with adequate overseas inputs, and instituted a domestic fund allocation policy favoring the steel and domestic coal industries. For the electric power sector, the national government established the Electric Power Development Company (EPDC) and invested in large-scale hydropower projects. In 1962, facing an international free-trade requirement, MITI abolished the policy of foreign currency allocation and instead began manipulating the market for petroleum products, controlling products' prices and the amount of output from domestic refineries in order to foster the industry. MITI also controlled importation of petroleum products, protecting the Japanese petroleum industry until the 1990s. These policies placed restrictions on the electric power sector; specifically, the sector was required to:

- use fuel oil from domestic refineries first, limiting the amount of imported fuel oil in order to eliminate the market surplus of fuel oil from domestic refineries
- refrain from using more imported crude oil than imported fuel oil, to sustain prices being charged for domestic fuel oil

These restrictions became effective in 1967, in the form of a committee recommendation, and remained in force until petroleum product imports were liberalized in 1996. The restrictions limited the electric power sector's crude-oil consumption and forced the sector to use fuel oil from domestic refineries despite its relative expense. The economic prospects of oil-based power plants deteriorated as a

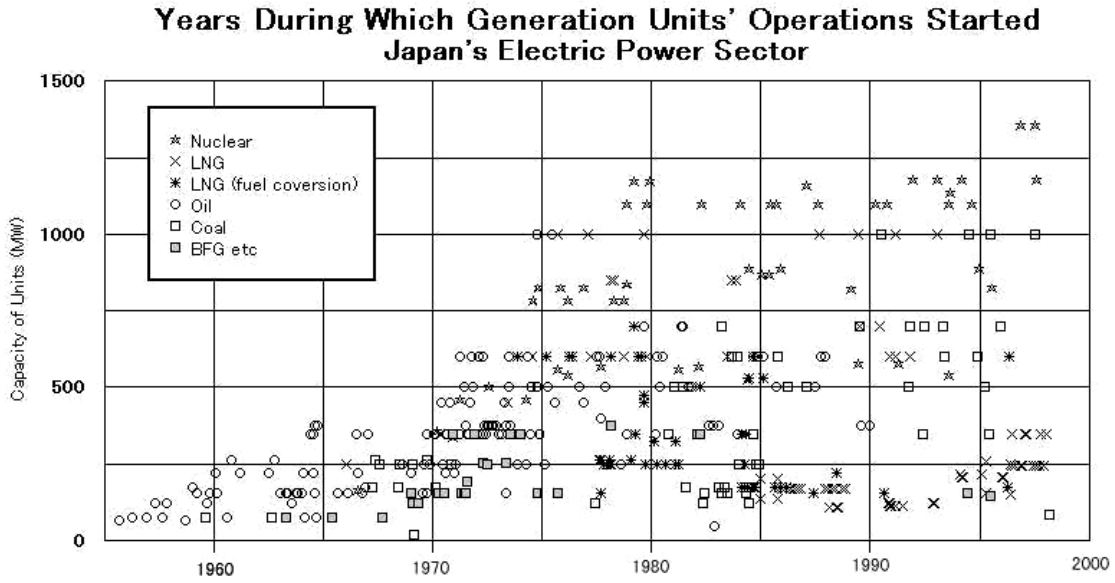
result of the market distortion, and companies in the electric power sector were unlikely to build new oil-generation units that would be subject to the regulatory risks posed by Japan's protective policies for the domestic petroleum industry.

C. The Portfolio's Evolution

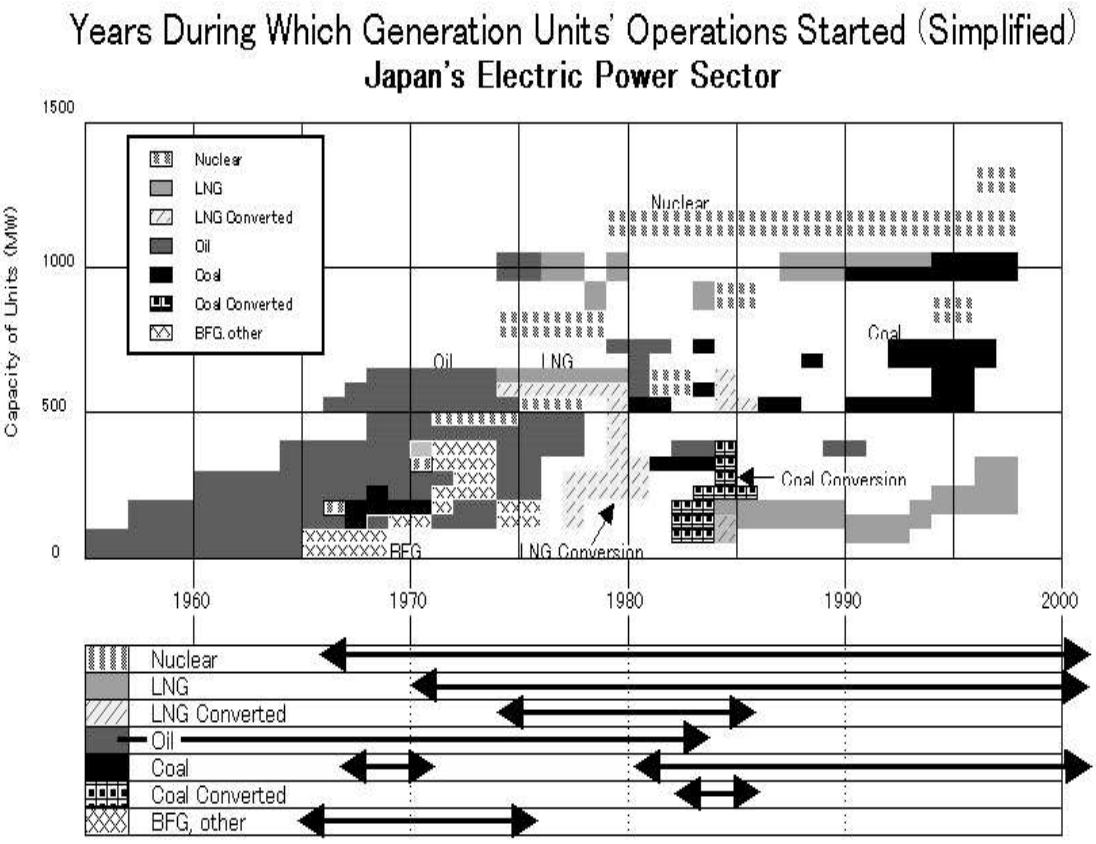
1. Periods favoring particular generation resources

Figure 4a shows the years in which operations started as well as unit sizes for nuclear- and fossil fuel-powered generation units in Japan's electric power sector (excluding the self-generation units run by consumers themselves). Coal-powered and nuclear units have increased in size more recently to pursue economies of scale, for utilization as base-load units since they have such low variable costs. As for LNG, Japan's electric power sector has employed combined-cycle technology since the 1980s; the first combined-cycle generation units started operation in 1984. The technology shift to combined-cycle units can be observed in Figure 4a by the fact that LNG units' capacity has decreased from 1,000 MW to 100–300 MW since the technology was first employed. Figure 4a also indicates that facility startup years center around certain periods favoring a particular type of generation. **Figure 4b** offers some explanation for this, showing the period concentrations of various sorts of generation facility startups, based on generation resources' development. Essentially, Japan's electric power sector focused on installations of:

- oil-powered units until the 1980s
- units owned jointly with steel producers (utilizing gases derived from production processes), intensively from 1969 to 1976
- nuclear units continuously since 1970
- coal units since 1981
- LNG steam turbine units from 1970; since 1984, the sector has shifted to installations of combined-cycle units



(Figure 4a)



(Figure 4b)

2. Oil-Powered Units' Fuel Conversion

Japan's electric power sector has converted oil-powered units to LNG- and coal-powered units. It acquired 17.6 GW of its total 49.1-GW LNG capacity by March 1997 by equipping 54 oil-powered units with capabilities to use natural gas. Many of these units began using these new capabilities between 1977 and 1985, especially intensively during the years 1977, 1979, and 1984: From September 1977 to March 1978, fuel conversions for a 2.4-GW generation capacity were completed at ten oil-powered generation units. Conversions for an additional 3.4-GW generation capacity at eight units were completed during the eight months from February 1979, and conversions for 3.5 GW more were completed at fourteen units during the seven months from March 1984.

Japan's electric power sector has acquired *coal*-powered capacity by fuel conversion, too: 3.5 GW of Japan's total 20.3-GW coal-powered capacity has been created by fuel conversions in eighteen oil-powered units. The conversion to coal for a 1.9-GW (total) generation capacity at ten units was completed in 1983–84.

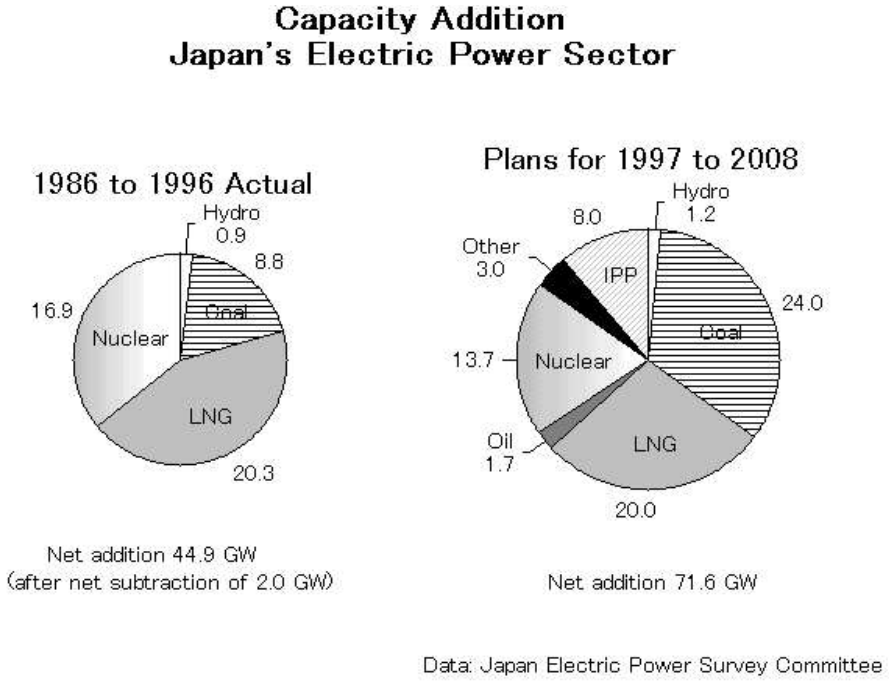
3. Tendency To Make the Same Choices

Companies have tended to make similar decisions within a given time frame about generation resources. When one company planning for additional units evaluates a certain generation resource as available and cheap, that resource is likely to receive the same evaluation by other companies. The companies' decisions about generation fuel type are in part based on fuel-price forecasts. Since each company's forecasts do not differ much from other companies' forecasts, because all are made in accordance with past trends, it is likely that many companies make the same decisions within the same time period. This tendency to make the same choices is seen in all countries, to some extent. For example, in the U.S, oil was primarily used when it was considered cheap; then the electric power sector dampened the demand for oil by implementing a policy of independence from this fuel after the Oil Shocks. Nuclear generation units were installed when price forecasts for fossil fuels showed an increase, and natural gas was utilized less in the 1970s and '80s when the scarcity of this resource was emphasized and its price was predicted to increase. Then, as the 1990s began, natural gas regained popularity in the course of industry deregulation and clean-air regulations. A simple tendency to make the same choices is one conclusion that could be drawn from the companies' behavior. This tendency follows naturally from the fact that generation resources come mostly from overseas so that the availability and procurement costs for a given generation resource have generally been the same for all the companies. Presumably, a tendency to make the same choices is more likely in Japan, which is heavily dependent on world markets, than in other countries, which often have their own economically competitive energy resources.

II. Japan's Portfolio of Generation Facilities by 2008

D. A. Current Plans for Adding to the Portfolio by 2008

Japan's Electric Power Survey Committee, assembled by and from participating companies in the electric power sector and heavy industries, collected information on planning projects for generation capacity installations during the eleven-year period from April 1997 to March 2008. According to the committee, about 70 GW of installation (in terms of net capacity addition) is being planned for this period, exclusive of self-generation unit additions by large industry consumers. Coal projects represent the greatest proportion of planned additions, 24 GW of the total, followed by 20 GW LNG projects and 14 GW nuclear projects (**Figure 5**). Projects representing 6.4 GW of IPPs' (independent power producers') plans have already won in the competitive bidding process conducted by major EPCOs from 1996 to 1998. Most (5.9 GW) of these projects will start burning fossil fuels around the turn of the millennium; 3.1 GW of the IPP projects will be powered by coal. Very few facility retirements are planned: an expected 2.5 GW in capacity. In Figure 5, actual additions from 1986 to 1996 are also shown for purposes of comparison with the Committee's survey.



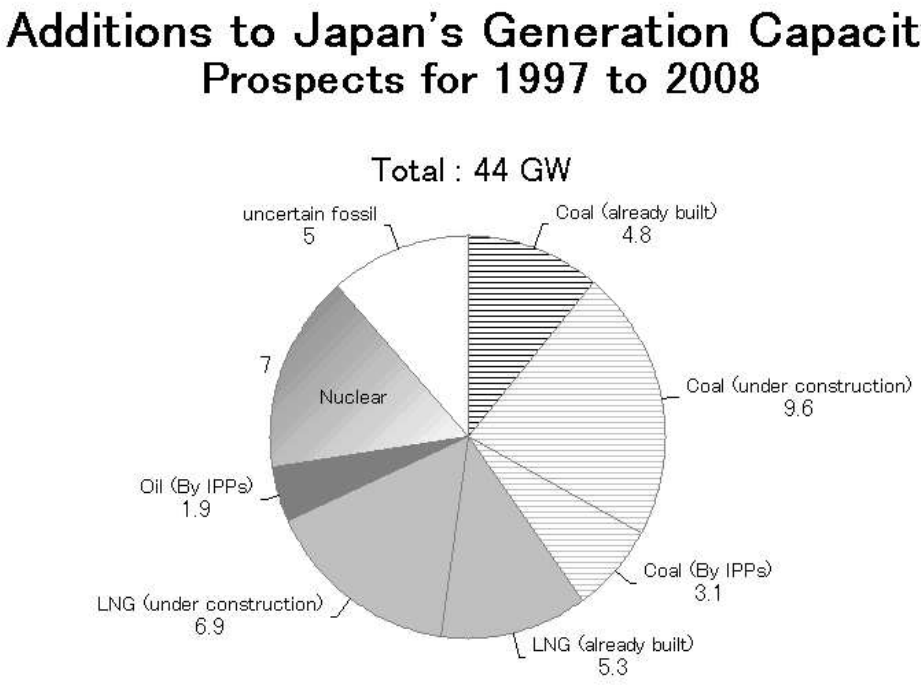
(Figure 5)

E. B. Probable Additions to the Portfolio by 2008

Japan's electric power sector acquired today's portfolio as the sum total of companies' individual decisions, as has been the case in other OECD countries. In looking at likely portfolio changes over the next decade, we must consider the following three factors:

1. A declining growth rate of peak load will dampen related investments
2. Government advocacy for nuclear installation will prove to be unattainable
3. Deregulation will have a limited impact on the portfolio in the next decade

Considering these three factors, the probable additional power-generating installations in Japan between April 1997 and March 2008 are shown in **Figure 6**.



(Figure 6)

Details follow.

A declining growth rate of peak load will dampen related investments

Returning to Figure 5, we note that in the decade prior to 1996, the net addition to Japan's electric power portfolio was 45 GW. Compared with this figure, the presently planned 70 GW addition seems excessive, especially taking into account the fact that demand growth early in the 1990s was backed by the frenzy of a "bubble economy." Since 1994, coincidental peak load for the Nine EPCOs has not increased.

At the end of fiscal year 1998, the major EPCOs downscaled their demand growth forecasts for the ten years ending in 2008; the peak load for the Nine EPCOs is now expected to grow by 1.8% per year until 2008. The new forecasts are based on a common assumption that gross domestic product (GDP) will grow by 2.1% per year. If this proves true, demand growth in terms of peak load will increase by about 35 GW during the eleven-year period from 1997 to 2008.

a. Demand decline and project postponement. To learn the reason for Japan's electric power sector' s excessive planning (for a 70-GW net addition between 1997 and 2008), we must go back to the summer of 1990. At that time, the reserve margin of the electricity supply, which had been over 10% for at least the prior five years, fell suddenly to 3.7%. The Nine EPCOs responded to the threat of such a short supply by laying out plans for additional installations of generation capacity and immediately began construction to prevent supply disruptions. The sudden drop in reserve margin, however, proved to be simply a bump in peak demand, rather than an indication of continuous steep growth: soon after the incident, peak load stopped growing.

Facing the present decline in demand growth, the Nine EPCOs are now postponing capacity acquisitions[5]. As a general rule, power companies slow their plans for additional generation capacity when demand forecasts show little growth, because excess capacity burdens management. The Nine EPCOs represent a significant proportion of Japan's electric power sector, and can adjust their plans for capacity additions cooperatively. Because the major participants in the sector are so few, the sector can respond rather quickly to declines in demand growth and shrink planned capacity additions. Moreover, the Nine EPCOs are working to reduce their investments not only to strengthen the EPCOs' financial structures in preparation for competition, but also to take into account the possible loss of large-load customers' power requirements to the IPPs' direct retail supply. At the same time, potential entrants to the sector find the generation business to be highly risky still, with long construction lead times and intensive capital requirements. New entrants are also discouraged currently by the decline in demand growth rate. As long as demand prospects remain weak, therefore, generation capacity additions will be sluggish. For the eleven-year period we have been considering, the question of net capacity additions to the electric power portfolio becomes the question of what to subtract from the additions being planned presently. I assume that capacity additions during this period will range from 35 to 45 GW, responding to the slow growth in peak load.

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[5] According to 12 December 1998 newspaper articles, Tokyo EPCO, which supplies one third of the electricity demand for the Nine EPCOs, had already committed to acquiring 18 GW capacity, though only 13 GW was expected to suffice until the year 2008. It was reported that postponing projects that would add capacity would be one of the primary issues in the integrated resource plan of 1999 submitted to MITI's Agency for Natural Resources and Energy (ANRE). Movements to postpone acquisitions had already begun among the Nine EPCOs; for example, Tohoku-EPCO was proposing to the Noshiro local community a five (or more)-year postponement of the company's Noshiro coal-powered unit project, in response to a decline in demand growth.

b. Projects completed or under construction as of December 1998. Returning to Figure 4b, we note that Japan's electric power sector recently installed coal-powered units and LNG combined-cycle units, as well as nuclear units. Between March 1997 and December 1998, coal-powered unit projects adding 4.8 GW of capacity were completed, and projects to add another 9.6 GW were still under construction. As for LNG units, newly started operations have added 5.3 GW capacity since March 1997, and 6.9 GW are still under construction. Beyond these, IPP projects for 5.9 GW are currently under construction or have started operation. Of the coal unit projects originally planned in 1997 to add a total capacity of 24 GW, 14.4 GW has been completed or started, and construction for about 10 GW has been put on hold. Of the original plans for LNG projects to add 20 GW of capacity, 12.1 GW has been completed or started, and construction for about 8 GW has been put on hold. The projects on hold are subject to indefinite postponement, with a low probability for construction to start anytime soon.

Figure 6 shows prospects for 2008 including a significant number of projects under construction and some completed between March 1997 and December 1998. Of a prospective 44 GW, traditional participants in the sector have started construction projects (some now completed) to yield about 31 GW, including 14.4 GW powered by coal, 12.1 GW by LNG, and 4.4 GW by nuclear. An additional 5.9 GW of new capacity has also been made available by IPPs (3.1 GW from coal, 1.9 GW from petroleum, and 0.9 GW from LNG units).

For the eleven-year period from 1997 to 2008, the combined capacity addition of fossil fuel-powered units and a probable 7 GW of nuclear-powered units may approach over 40 GW, sufficient to meet the forecasts of a 35-GW growth in peak demand. If demand growth climbs more than is currently predicted, competitive bidding for additional acquisitions of thermal-powered capacity is probable, though the coal and LNG projects (18 GW capacity) that have been postponed by traditional EPCOs already have government approval, so may be given preference. Japan's electric power sector will concentrate mainly on coal-unit installations in the coming decade. As will be noted later in this report, the national government currently recommends that 25 GW of additional nuclear capacity be installed by 2010, though this is not feasible. We might also note here in passing that the decline in demand growth has deprived the electric power sector of room for more nuclear power; needless to say, traditional participants in the sector who are nuclear developers have had to reduce costs and are becoming discouraged about the prospects for developing new nuclear sites.

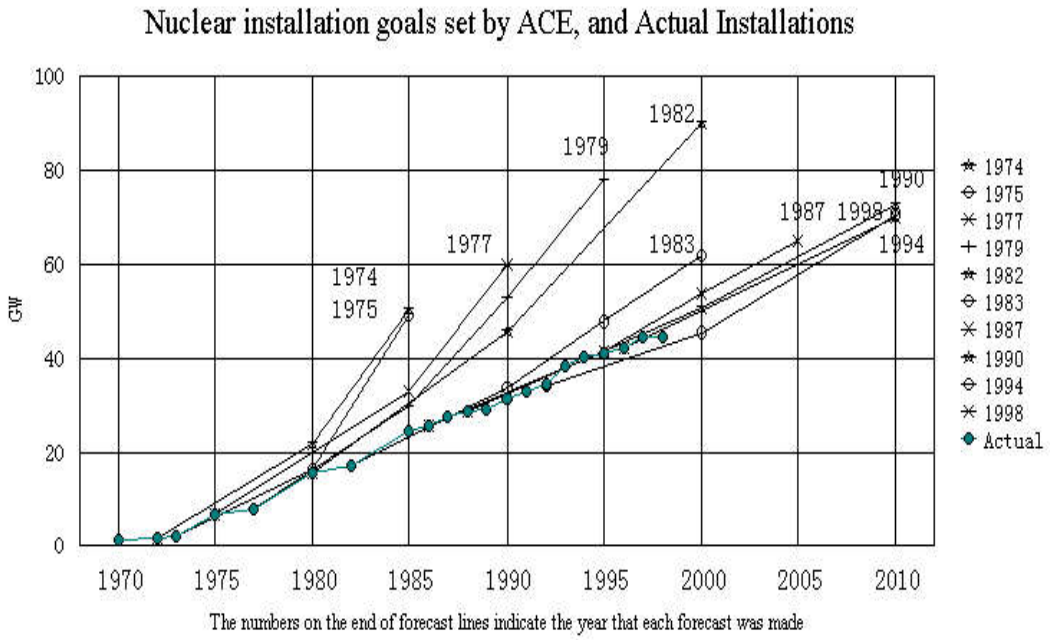
2. Government advocacy of nuclear installation is impractical

a.Less nuclear installation than recommended by government. The Japanese government declared that the nation would reduce its carbon dioxide emissions to 6% less than 1990 levels by 2010, in the Kyoto Protocol's third Conference on the Parties (COP3), held in December 1997. To achieve this goal, the Electric Utility Industry Committee (EUIC) in March 1998 set a goal for the electric power sector to reduce its emissions to 8.8% less than 1990 levels by 2010. As is known worldwide, the Japanese

government stated that Japan would add 25 GW of nuclear capacity to the existing 45 GW by 2010, and keep the overall utilization rate of nuclear units at a high of around 78%. In reality, however, Japan's electric power sector had already planned installation of only 14 GW of nuclear capacity, to be brought online between March 1997 to 2008. Between March 1997 and COP3, 2.5 GW started operation, but no additional planning for nuclear units was made. Rather, as of March 1997, only 11.5 GW of additional nuclear installations (nine projects) was planned to start operation between COP3 and 2008. So, if Japan does in fact add 25 GW of nuclear capacity between COP3 and 2010, more than 10 GW of nuclear power must be installed in the last two years before 2010. Of the nine projects currently planned, five are additional unit installations at already developed sites, while four are installations at new sites that require development. For the next decade, nuclear units will inevitably be installed mainly at already developed sites, since site development requires public acceptance within local communities, and recent movements for referenda and rising "not in my backyard" (NIMBY) sentiments are posing difficulties for site development, especially for nuclear power plants. Moreover, nuclear units are to be located in rural areas far from load centers, so new sites will require high-voltage transmission lines to the load centers. Under today's circumstances—cheap, available fossil fuels and strong pressures to reduce costs—it is unlikely that private companies will make new commitments to construct more nuclear units. Without specific measures offering economic incentives for nuclear installations, an additional 25 GW of nuclear capacity will hardly materialize.

b. Background to the government's goal of adding 25 GW of nuclear capacity. Japan at present lacks specific political measures to mandate the additional 25 GW of nuclear capacity and thereby bring its nuclear generating capacity to 70 GW by 2010. The plan is also economically infeasible, in part. The question therefore becomes whether the government will increase the feasibility of its goal through such measures as taxation, subsidies, or other economic boosts for nuclear installations. In fact, Japan's government controls an extraordinary amount of money related to energy policies, through its taxation of petroleum products and subsidies from electricity rates to local governments in areas where power plants are built. For example, in 1998, $42 billion was collected from petroleum taxes and spent largely for road construction and another $2 billion was collected from electricity rates and dispersed to local governments. Still, these measures are in force to redistribute money, not to resolve problems of economic infeasibility. Since the existing policies deal with a great amount of money, pressures will probably mount to restructure them someday, though this is unlikely in the next decade. Regrettably, the government has set unattainable goals repeatedly without effective policy measures, and its current 70-GW goal may prove to be just one more unattainable goal.

The 70-GW goal was based on projections made by the Advisory Committee for Energy (ACE) under MITI's supervision, in an effort that has spanned the last 30 years (**Figure 7**).



(Figure 7)

A glance at Figure 7 shows that the slope of the projected curve for 1998 appears consistent with recent past trends. However, ACE's past projections consistently overestimated the pace at which nuclear facilities have been installed. In the 1970s, the projection curves were drawn on the basis of quadratic equations reflecting an expectation that nuclear power would become an energy substitute for petroleum, and as a resolution to steep growth in demand. As the years passed (during the 1980s), the projection curves became increasingly linear for greater consistency with past trends. The consistency between the 1998 projection and the trend of actual installations derives from the fact that nuclear capacity was being installed at a stable pace. There is no guarantee that this pace will continue, however. Moreover, the goal of about 70 GW by 2010 was set in 1990 when environmental concerns were rising internationally[6]. However, the government held to its projection for almost a decade, despite less growth in peak demand and even though circumstances moved against nuclear installations as a result of rising antinuclear movements and site depletion in the sense that Japan has been running short of available land for nuclear sites.

c. Deregulation's impact on nuclear installations. Because nuclear power has been considered the centerpiece of Japan's policy to lessen the nation's dependence on oil, it was considered separate from fossil fuel-powered thermal generation during the deregulation debate. As a consequence, competitive bidding was introduced for acquisitions of thermal capacity only. Nuclear development escaped

[6] Nuclear installation was one of those recommendations that the national government made in consideration of environmental issues early in 1990's. The government showed its direction by ACE's publishing a report titled"Fourteen Proposals for a New Earth", subtitled "Policy Triad for Environment, Economy and Energy" (November 1992). Nuclear installation is strongly emphasized by third recommendation in this report.

competition with IPP projects burning fossil fuels on grounds of construction. The government even decided that back-end costs should be collected from all consumers of electricity.

However, nuclear power was given no such sanction in terms of cost recovery. No guarantee was given owners of nuclear generation units to recover their costs fully. Inevitably, companies became more cautious about building additional nuclear units. The national government and owners of nuclear units had been claiming nuclear power to be the least expensive form of generation, based on the premise of ever-increasing fossil-fuel prices [7]. In fact, however, nuclear installation and operation requires the development of long transmission lines and the deposition of decommissioning costs, as well as advertising to gain public acceptance. Moreover, nuclear power must run as baseload units, and once the electric power sector holds excess capacity and the utilization rate declines, companies risk failure to recover their full costs. Doubt about the lower cost of nuclear units has risen in these days of cheap fossil fuels and market stability. During the course of deregulation in Japan, retail competition will be introduced to large-load customers in 2000; companies will then be pressured increasingly to lower costs. Despite the fact that a nuclear unit has lower variable costs than does a fossil fuel-powered unit, by its very nature, an enormous capital investment is needed for installation; any new addition of nuclear units therefore cannot be expected when the risk of failure in cost recovery is rising[8]. During the period 1997–2008, taking into account postponements and project changes, only 7 GW of the originally planned 14 GW capacity is expected to be built, as shown in Figure 6 including 2.5 GW that started operation before COP3.

3. Deregulation will have a limited impact on the portfolio in the next decade

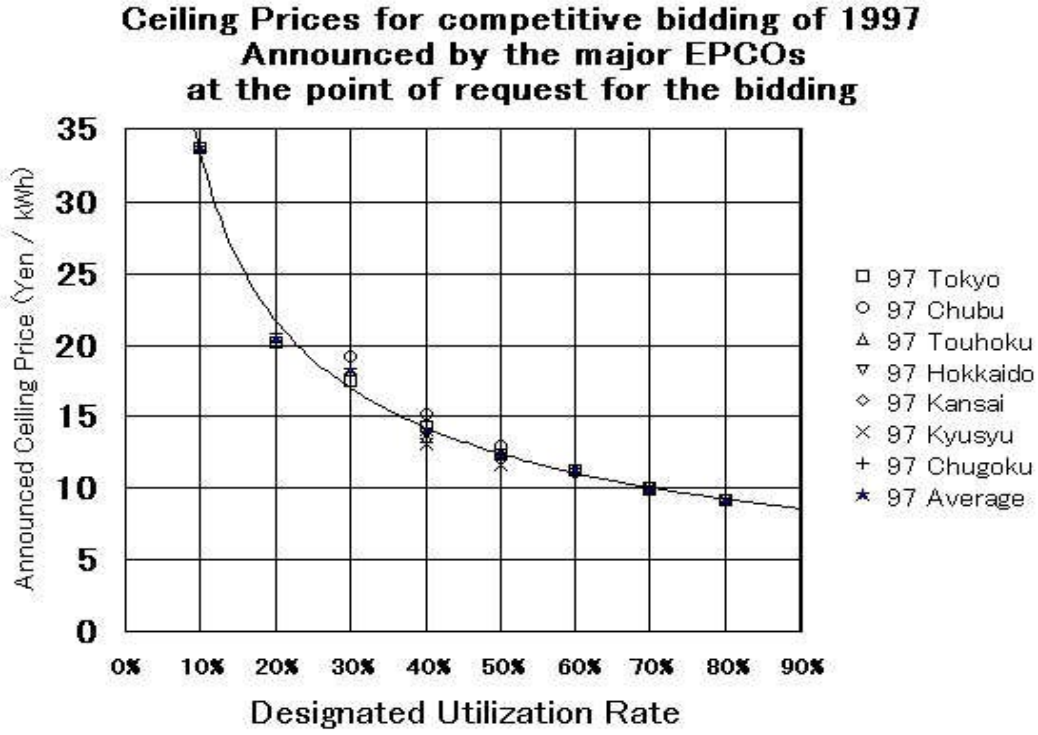
In 1995, the amendment to the Electric Utility Industry Law, which is at the center of the regulatory codes for Japan's electric power sector, passed the Diet, coming into effect in December. One intention for the amendment was to shift the initiative, streamlining government approval procedures and relieving qualification requirements. Another intent was to relieve entry regulation to the sector, making it possible for electric utility companies to acquire generation capacity from independent power producers (IPPs) through competitive bidding. In other words, new IPPs were granted to wholesale their power to the major EPCOs. The major EPCOs awarded IPP projects for 6.4 GW of generation capacity through competitive bids held from 1996 through 1998. From the year 2000 on, it will be compulsory for

[7] According to a study of generation costs conducted by MITI in 1992, the average cost of generation at nuclear units was 9 yen/kWh, compared to 9 yen/kWh at LNG units and 10 yen/kWh at coal and oil units (given an assumed utilization rate of 70% for all generation types, and the assumption that all plants started operations in 1992).

[8] This does not imply that nuclear units are not competitive. The Nine EPCOs hold generation units of various types, and gave priority to nuclear units' operation, in dispatching. A high utilization rate (about 80%) keeps nuclear units competitive despite high fixed costs. Because nuclear units require lower variable costs, existing units with lower marginal costs may be run first despite competition. Nuclear units will remain competitive as long as they maintain a high utilization rate.

the major EPCOs to conduct competitive bidding when planning acquisitions of thermal-generation capacity powered by fossil fuels, including their own projects. The 1999 Amendment of the law will open retail competition between the major EPCOs and IPPs to supply the large-load (>2 MW) customer class connected to the major EPCOs' network through high-voltage (>20 kV) transmission lines, on the basis of long-term contracts. The aforementioned amendment makes it possible for IPPs not only to *wholesale* electricity to the major EPCOs, but also (from the year 2000 on) to *retail* electricity directly to large-load customers by way of the major EPCOs' supply network, via payment of a transmission-line usage fee. These changes in the regulatory framework require economic efficiency in the electric power sector, in terms of generation resource choices. However, just as capacity additions to the national generation portfolio for the next decade are limited because the growth rate is shrinking, so the IPP's role is limited in shaping the portfolio.

a. Competitiveness of IPPs relative to traditional sector participants The rationale that introducing competition to regulated utility companies will lower the cost of service primarily stems from companies' efforts to defeat their opponents in competition. This rationale also stems from optimization of resource employment (less input for the same amount of output). As entry regulation is eliminated, permitting new entrants, the sector becomes able to utilize resources it could not have used otherwise—not only fuels and material, but also land property, personnel, and know-how for reducing costs. For example, as owners of self-generation units enhance their generation capacity and start to sell off surplus generation, obviating the need for traditional utilities to initiate green-field projects to acquire additional supply capacity, less investment (input) will generate the same amount of electricity (output). In Japan, potential IPPs generally have land resources at manufacturing sites closer to (and in many case, within) major metropolitan load centers than are sites that could be developed by traditional electricity sector participants. Some potential IPPs can also take advantage of residual oil and gas derived from production processes at their refineries and steelworks, or use the heat from power generation for their own production processes. The combination of surplus land resources and such engineering reintegration advantages can enable IPPs to generate electricity at lower cost than can the EPCOs. **Figure 8** shows ceiling prices set by the major EPCOs at the competitive bidding in 1997. The major EPCOs solicited bids after designating the utilization rates of their requested capacity. The regulatory agency stated that winning bids in the last three years have proposed projects to sell electricity at prices less than 80% of the ceiling prices announced by the major EPCOs, though detailed figures were not divulged.



(Figure 8)

b.IPPs' limited role in adding capacity. In 1997, MITI's Agency for Natural Resources and Energy (ANRE) studied IPPs' potential generation capacity and concluded that potential existed for the IPPs to build facilities that could supply an additional 38 GW capacity. As we have already noted, both the major EPCOs and large-load customers could purchase power from IPPs if this extra capacity were built. However, generation capacity additions by IPPs will be limited in the coming decade.

In terms of wholesale transactions, the major EPCOs' requests for IPP project proposals are based on capacity-acquisition plans in the EPCOs' resource plans submitted to ANRE. Requested amounts change with the major EPCOs' capacity-acquisition plans. As the demand forecast for electricity falls, requested amounts for IPP projects also diminish. Moreover, capacity-acquisition plans for about 50 GW of the total planned (70 GW, as of March 1997) had already received approval from the national government before the first legislation for deregulation was enacted in 1995. Projects for 18 GW of the approved 50 GW have been reserved. Though this prior government approval does not guarantee exclusive rights for capacity addition in a legal sense, there has been no move to require already-approved projects to compete with new IPP projects. Projects that have already been approved take precedence over future IPP projects.

In terms of direct retail to large-load customers, IPPs directly supply large-load customers with or without transmission services provided by the major EPCOs' transmission lines.

The retail markets in which IPPs sell electricity to distant customers via the major EPCOs' transmission lines are not likely to grow dramatically in the next decade. Market expansion for IPPs'

retail supply to distant customers depends on the transmission-line usage fee that IPPs must pay to the major EPCOs. The fee may vary with the EPCO, but is to be set at around 3 yen/kWh. Large-load customers purchasing power from the major EPCOs pay 10 yen/kWh, more or less, so IPPs must generate electricity for less than 7 yen/kWh to be attractive suppliers. Returning to our discussion of Figure 8, winning bids in the competitive bidding of 1997 proposed prices less than 80% of the major EPCOs' ceiling prices, so 7 yen/kWh is achievable for IPPs' newly built units only if the IPPs can run their generation facilities around the clock with a high levelized load. More than 60% of potential (largeload) customers having an around-the-clock profile for electricity consumption are already equipped with their own self-generation units, however, so IPPs with newly built units wanting to retail their power may have difficulty acquiring distant customers whose combined load is levelized. Aggregation of customers is critical to load leveling, but the issue has always been considered "cherry picking." IPP's role in capacity additions will be limited until the transmission fee is reduced and the aggregation issue is settled.

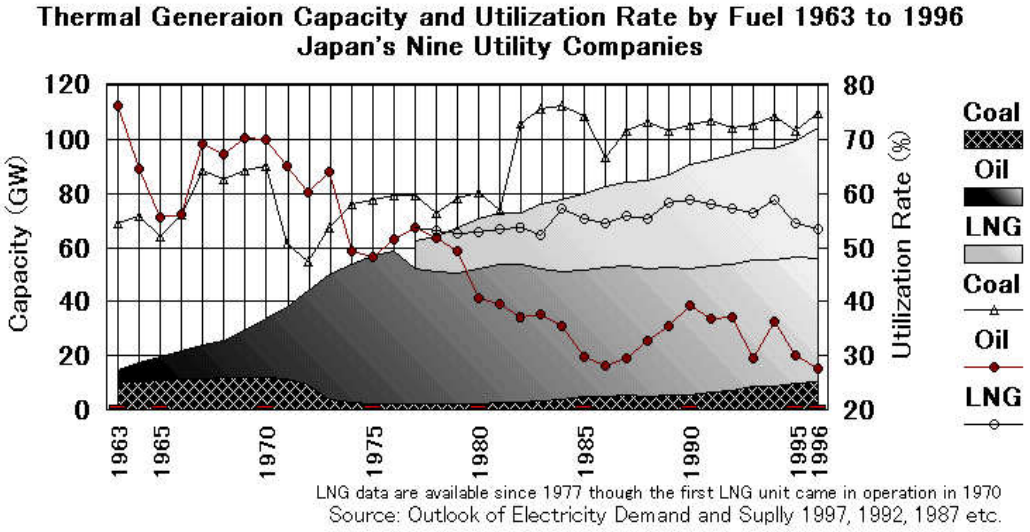
On the other hand, IPPs' retail supply without the major EPCOs' transmission services also will not grow dramatically in the next decade, though the amendment of 1995 offered retail suppliers relief from the requirements of government approval and qualification. This "authorized confined area" (ACA) service existed prior to recent deregulation movements, mainly to deal with industrial complexes. Generation facilities owned by industrial consumers had been selling power to other consumers within the same industrial complexes. Specifically, in 1997, such generation facilities (totalling 6.2 GW in capacity) sold 36.8 thousand GWh of electricity within confined areas. This type of service has little room left to grow. Perhaps a boom in the nation's economy is needed for ACA service providers to construct additional generation capacity. As for IPPs' retail supply service without the major EPCOs' transmission service, IPPs' role in capacity additions to Japan's electric power sector's portfolio will be quite small.

However, the IPPs' role limitation in terms of capacity addition is no indication of their role in terms of industry restructuring. Elimination of the entry regulation optimizes resource employment, enabling the sector to utilize resources that it has not had before.

For example, Shikoku EPCO, one of the Nine EPCOs, started purchasing power from the Minobu power plant in 1994, since the electricity load for Shikoku's supply system seemed to be increasing. The Minobu power plant had been built by Sumitomo Chemical in 1975 to supply electricity for its aluminum smelter as self-generation units. In 1982, the power plant halted operations when Sumitomo Chemical closed the smeltery. The regulatory commission had qualified the company as a power supplier, however, and Minobu power plant resumed generation to sell power outside the fence. As entry regulation to the electric power sector is relieved, this scenario will occur increasingly, though we cannot determine how much of the self-generation units (22.9 GW in capacity, as of March 1997) will inject power into the network.

At present, Japanese industries' (especially petroleum refineries, chemical and steel plants, and smelteries) excess production capacity sometimes makes them uncompetitive in the global economy. Companies in these industries are moving toward mergers and joint operations to cope with excess production. In many cases, their production facilities are equipped with self-generation units. While some production facilities have halted operations, their generation units are still standing and seeking purchasers. In such cases, the generation units' owner is willing to sell electricity at a price just high enough to recover variable costs, even though past investments have not yet been fully recovered. Power from facilities of this kind thus may sell at average variable cost, with no concern for fixed-cost recovery, yielding prices as low as 4 yen/kWh when fossil fuels are cheap[9].

c. IPPs' role as peaking power. For the eleven-year period ending in 2008, IPPs will play a limited role in Japan's electric power sector in terms of sales as well as capacity additions. **Figure 9** shows the utilization rate of thermal generation units in the sector, by fuel type, along with installed capacity owned by the Nine EPCOs. Oil-powered capacity has been held to a level of 45 GW, more or less, since the 1980s, while utilization of the capacity has been reduced from more than 50% before 1980 to 30-40% after 1980 (Figure 9). With low petroleum prices (even when these are not so low as recent $10/barrel for crude oil), the oil-powered capacity owned by the major EPCOs is competitive enough to deprive new IPP projects of opportunities to run during mid-load hours. In fact, we must note even the possibility that oil-powered capacity could displace LNG and coal units from operation during mid-load hours, reducing the utilization rates of LNG and coal units to lower levels than at present.



(Figure 9)

[9] This number is a rough calculation. In fact, the major EPCOs indicated in their ceiling prices submitted for the 1997 competitive bidding that a fuel price of 2.5 yen/kWh and an operational cost of 1.5 yen/kWh would be adequate for them to recover variable costs.

As Japan's electric power sector has pursued LNG and coal as oil substitutes since the early 1970s, the sector has increased its consumption of these resources. The sector procured LNG and coal with "take-or-pay" clauses in long-term contracts with overseas resource developers, and imports grew in proportion to capacity installations. Also, Japan's power sector designated the role of each unit by fuel type: coal units supply base loads, LNG units handle mid loads, and oil units are reserved for peak loads. Utilization of coal and LNG units has therefore been kept stable, with oil units supplying spike loads, as the sector has adjusted the output from oil-powered units to changes in total electricity load on the supply systems. Specifically, the sector has increased its utilization of oil units when the total demand for electricity has grown faster than had been thought, and has decreased oil utilization in the opposite case.

At the recent rapid pace of capacity addition, at least 3 GW of oil-powered capacity is utilized within less than three months by three major EPCOs supplying half of the total electricity load on Japan's electric power sector [10]. For the eleven-year period we have been considering, this less-utilized capacity can increase electricity output, since the restriction on petroleum imports imposed on the sector since 1967 was removed in 1996. Most generation units constituting Japan's surplus oil-powered capacity were built in the 1960s, and enjoy an advantage over forthcoming IPP projects by having already recovered their investment. Though the sector had requested that IPP projects supply mid or base loads from 1996 to 1998 to simplify dispatch, the major EPCOs will solicit peak load supply if they ever again need to acquire additional capacity.

[10] In June 1998, Tokyo-EPCO, Chubu-EPCO, and Kansai-EPCO issued independent statements that they would operate some of their oil-powered capacity only seasonally, or shut down units that had been spinning for a year as operational reserves for ancillary services. Tokyo-EPCO closed two units to save a capacity of 0.95 GW, Chubu-EPCO shut down six units to save 2.096 GW, and Kansai-EPCO did not specify a targeted savings in capacity, but mentioned a possible halt of operations at some of its seventeen units, representing a total capacity of 2.7 GW.

III. Conclusion

Though intuitive assertions must be avoided as a general rule, I did make one bold assumption in speculating on the Japanese electricity sector's changes in portfolio over the next decade. This was that the net addition would be only 35–45 GW, despite the existence of projects that could supply Japan with 70 GW of additional capacity.

It can be argued that sector deregulation has boosted net additions to the portfolio. However, considering the facts that during the last decade (1986–96) the net addition to Japan's generation capacity was 45 GW, and peak-load growth in the U.S. (whose electric power generation is four times that of Japan) was 140 GW over the same period, a 70-GW addition to Japan's electric power sector over the next decade is surely excessive. In a deregulated market, supply responds not to demand but to price; however, for Japan's part, the underlying question is whether the situation is good enough for new entrants to make a profit. IPPs won't build a plant when they think the project is not profitable even if market price of electricity is generally high.

The forecast I used to deduce that peak-load growth in Japan will be 35 GW during the eleven-year period from April 1997 to March 2008 was made by the major EPCOs for their 1998 annual submission to MITI's Agency for Natural Resources and Energy (ANRE). The EPCOs made this forecast on the assumption that the GDP growth rate will remain at 2.1%, which seems to be an overestimation. The Nine EPCOs are therefore postponing projects in accord with their own demand forecasts, which suggest a decline in the growth rate of peak load. The EPCOs do not want to suffer from overcapacity, as the U.S. did in the 1980s. The Nine EPCOs' behavior sends a signal to other companies, especially potential entrants, which are not encouraged to enter this capacity-intensive business requiring long construction lead times when demand is growing slowly.

Thus, Japan's generation capacity additions to its present portfolio will concentrate on projects that were already under construction at the time the EPCOs' forecast was revised downward. As a result, despite government statements, nuclear power does not hold good prospects, and coal units will represent a relatively large proportion of the total addition. Japan's government should not be blamed for its probable failure in predicting additional nuclear installations of 25 GW, but should be blamed for continuing to send wrong signals about coal imports, knowing that these will probably increase.

Approximately 17 GW of coal-powered capacity is projected to be added to Japan's electric power sector by 2008. Even with today's low crude-oil prices, the marginal cost at coal units is lower than the marginal cost at oil-powered units, so utilization rates at coal units as a whole will continue at 70% as long as coal remains the preferred fuel. In the absence of restrictions, the sector's annual coal consumption will increase by 38 million tons.

A change in the portfolio of generation facilities in Japan's electric power sector will indicate that GHG reduction will be difficult, and that growth of the international coal market will remain stable.

Terms and Abbreviations

ACE (Advisory Commission for Energy) – Under supervision of MITI, the commission conducts research on long-term national energy matters.

ANRE (Agency for Natural Resources and Energy) – Under the MITI umbrella, the agency implements energy-related regulations and policies.

EUIC (Electric Utility Industry Committee) – A MITI conference for electric utility regulation. MITI chooses committee members from a broad roster of stakeholders in academic institutes, power industries, heavy industries, commercial consumers, residential consumer advocates, and ANRE to prepare an advisory report for decision-makers.

The major EPCOs – The Nine EPCOs plus Okinawa-EPCO: together, these represent the only companies providing all three functions in the electric-utility business (generation, transmission, and distribution).

The Nine EPCOs (electric power companies) – The nine dominant electric utility companies in Japan, vertically integrated and investor-owned. The boundaries of each service territory are drawn in accordance with the boundaries of a political region consisting of several prefectures. The Nine EPCOs are Hokkaido-, Tohoku-, Tokyo-, Chubu-, Hokuriku-, Kansai-, Chugoku-, Sikoku-, and Kyusyu-EPCO.

EPDC (Electric Power Development Company) – A government-financed electric power wholesale company that will be privatized in 2003, during the course of government restructuring. Two thirds of EPDC's equity is currently owned by the Ministry of Finance; the rest is owned by the Nine EPCOs.

IPP (independent power producer) – Non-utility generator that does not own a distribution network. Essentially, a new entrant to the electric power sector during the course of deregulation (Japan's 1995 Amendment allows the major EPCOs to acquire additional generation capacity from organizations outside the traditional generation sector).

JAPC (Japan Atomic Power Company) – A nuclear power wholesale company owned by the Nine EPCOs, EPDC, and companies in heavy industry, established primarily by the Nine EPCOs; the first commercial nuclear power plant in Japan.

Jointly-Owned Units – Generation units whose owners are among the Nine EPCOs and heavy industry. Most JOUs are owned by one of the Nine EPCOs and a steel company; some units are owned by two of the Nine EPCOs.

MITI (Ministry of International Trade and Industry) – Japan's regulatory authority over industry sectors.

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